Design, Construction, and Operation of Dynamic Underground Stripping Facilities at Lawrence Livermore National Laboratory

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Introduction

Dynamic Underground Stripping Process Description

Dynamic Underground Stripping is a thermally enhanced remediation technique that uses electrical energy and steam injection to heat the contaminated subsurface. Electrical heating targets the tight, clay rich zones that steam will not penetrate. Steam is used to heat the more permeable layers. Steam injection also sweeps free phase contaminants floating on the water table or trapped below it, towards centralized extraction wells. Vacuum venting through one or more extraction wells further reduces contaminants left in the hot formation at greatly enhanced rates. Contaminated effluent streams (vapor and liquid) are treated at the surface by commercially available treatment technologies. The possibility of recontamination of the ground water from contaminated overburden is significantly reduced due to the removal of the source term.

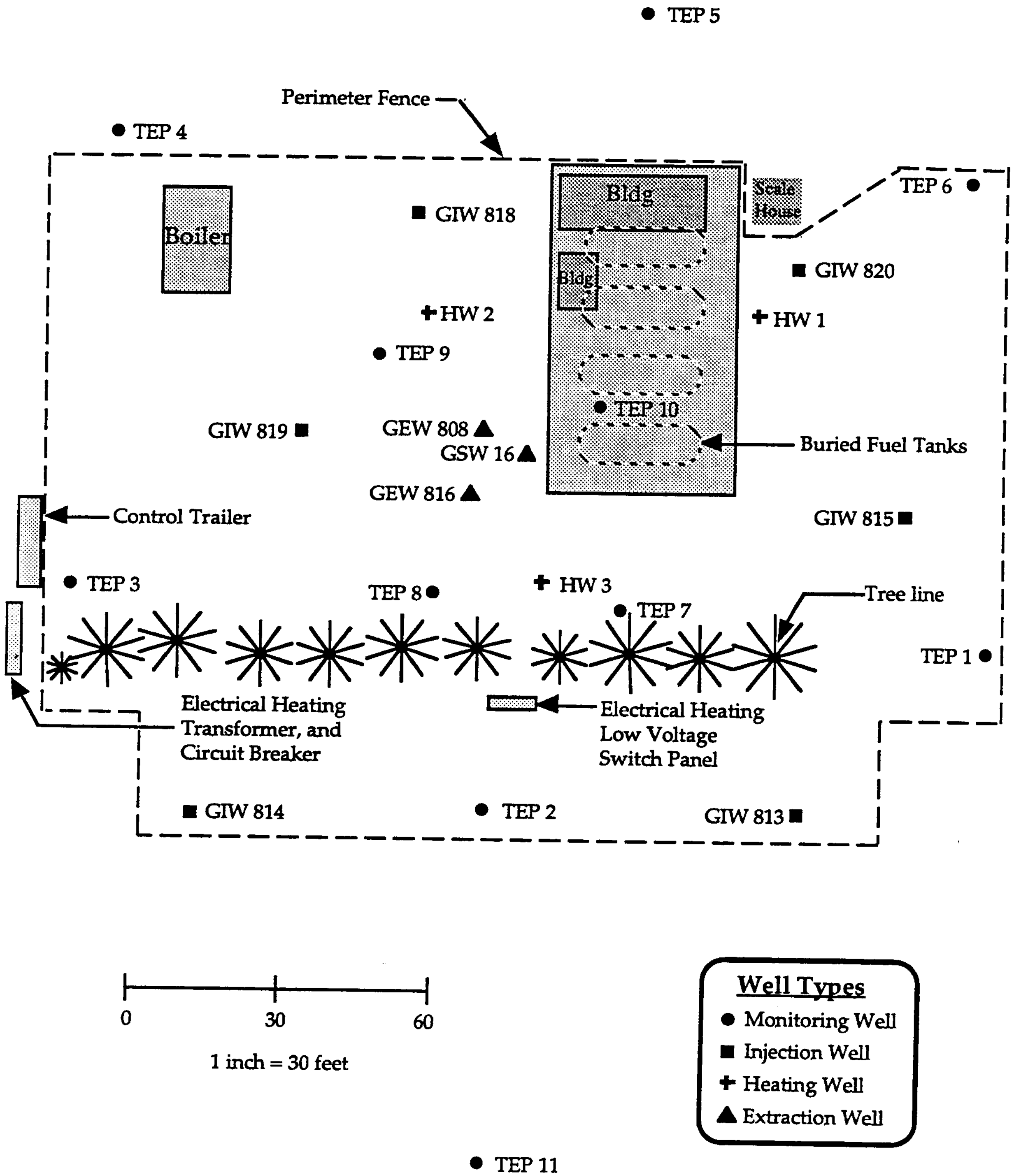
The process is applicable at both NAPL (Non-Aqueous Phase Liquid) and DNAPL (Dense Non-Aqueous Phase Liquid) contaminated sites. Dense contaminants such as TCE that sink below the water table are the most difficult to remediate using pump and treat technologies. The Dynamic Stripping technique will address the problems associated with DNAPL sites by displacing free product towards extraction wells. Once there, it can be easily removed in both liquid and vapor phases.

General Site Description

The Dynamic Underground Stripping process has been applied to a gasoline spill at the Lawrence Livermore National Laboratory. The gasoline contaminated site was once a gas station serving the Laboratory and the U. S. Navy before it. Gasoline leaked from storage tanks over a period of years. The most recent estimate of the quantity of gasoline trapped in the formation is approximately 27,300 liters (6,200 gallons). This estimate is based upon numerous characterization wells drilled in the area and excludes free product floating on or below the water table. Using the Dynamic Stripping technique, a total of 27.1 m^3 (7,200 gallons) of gasoline has been removed.

Six combination steam injection-electrical heating wells were installed on the perimeter of the gasoline plume. The injection wells were placed in an approximately circular pattern with a maximum diameter of 52 meters (170 feet) and a minimum diameter of 36.6 meters (120 feet). Two extraction wells were installed near the center of the spill close to an existing extraction well. In addition, three wells with only electrical heating casings were installed, two at an approximate radius of 9 meters (30 feet) from the extraction wells and one at 18 meters (60 feet) Figure 1 shows the general site layout.

Figure 1. Dynamic Stripping Project Gas Pad Area



Engineering Objectives

The engineering objectives of the remediation effort at the Livermore gas spill site were:

1. Design and construct full scale surface facilities necessary for the process such as steam injection and electrical heating equipment.

2. Modify the existing effluent treatment system for use during Dynamic Stripping.

3. Obtain data necessary to determine the most effective operational strategy.

4. Further refine and improve the design and construction of steam injection and electrical heating wells.

5. Establish the costs associated with construction and operation of dynamic stripping facilities.

6. Remove as much contamination as possible.

Dynamic Stripping Well Construction

Well Construction Overview

Well construction began in December of 1991. A total of 22 wells were constructed at the site during a six month period. Eleven of the wells were combination geophysical monitoring wells used for Electrical Resistance Tomography imaging (ERT), induction logging, and temperature measurements. Five were combination steam injection-electrical heating wells placed around the perimeter of the plume. One was steam injection only and three were electrical heating only wells. Two extraction wells were drilled at the center of the pattern near the source of the gasoline leak. In addition to the 22 wells, seventeen of the borings were drilled, 6.1 meters (20 foot) deep and used for tiltmeter instruments. Tiltmeters were used to map the location of the steam front during steam injection operations. A brief summary of the wells used at the gas pad is given in Table 1.

Table 1. Identification of wells and boreholes drilled at the gas pad.

Well Identifier	No. of Wells	Purpose	Nominal Dimensions	Drilling Method
TEP	11	Geophysical Imaging (ERT, Temp.)	0.28 m Dia. x 50 m Deep (11 in Dia. x 165 ft Deep)	Hollow Stem Auger
TLT	17	Tiltmeter (Steam Front Mapping)	0.3 m Dia. x 6 m Deep (12 in Dia. x 21 ft Deep)	Auger
HW	3	Electrical Heating	0.3 m Dia. x 36.2 m Deep (12 in Dia. x 120 Deep)	Hollow Stem Auger
GIW	6	Steam Injection Electrical Heating	0.36 m Dia. x 44 m Deep (14 in Dia. x 145 ft Deep)	Reverse Circ. Rotary
GEW	2	Liquid and Vapor Extraction	0.36 m Dia. x 47 m Deep (14 in Dia. x 155 ft Deep)	Reverse Circ. Rotary

The wells were drilled by one of three methods. Small pilot holes for the steam injection wells were drilled with a hollow stem auger. They were extensively sampled for mineralogy, biology and contaminant concentration levels to establish a baseline for comparison after heating. The pilot holes also confirmed the absence of free product gasoline at the perimeter injection locations. Final drilling of the steam injection and extraction wells was performed using the reverse circulation rotary method. This method was chosen minimize the infiltration of drilling fluids into the formation that could reduce flow into and out of the well during injection or extraction operations. This was of particular concern in the vadose zone, where well development was limited.

The geophysical monitoring wells and the electrical heating only wells were drilled with a hollow stem auger. They were similarly sampled for mineralogy, biology and contaminant concentration levels during drilling. The tiltmeter holes were drilled with an auger rig. No samples were taken.

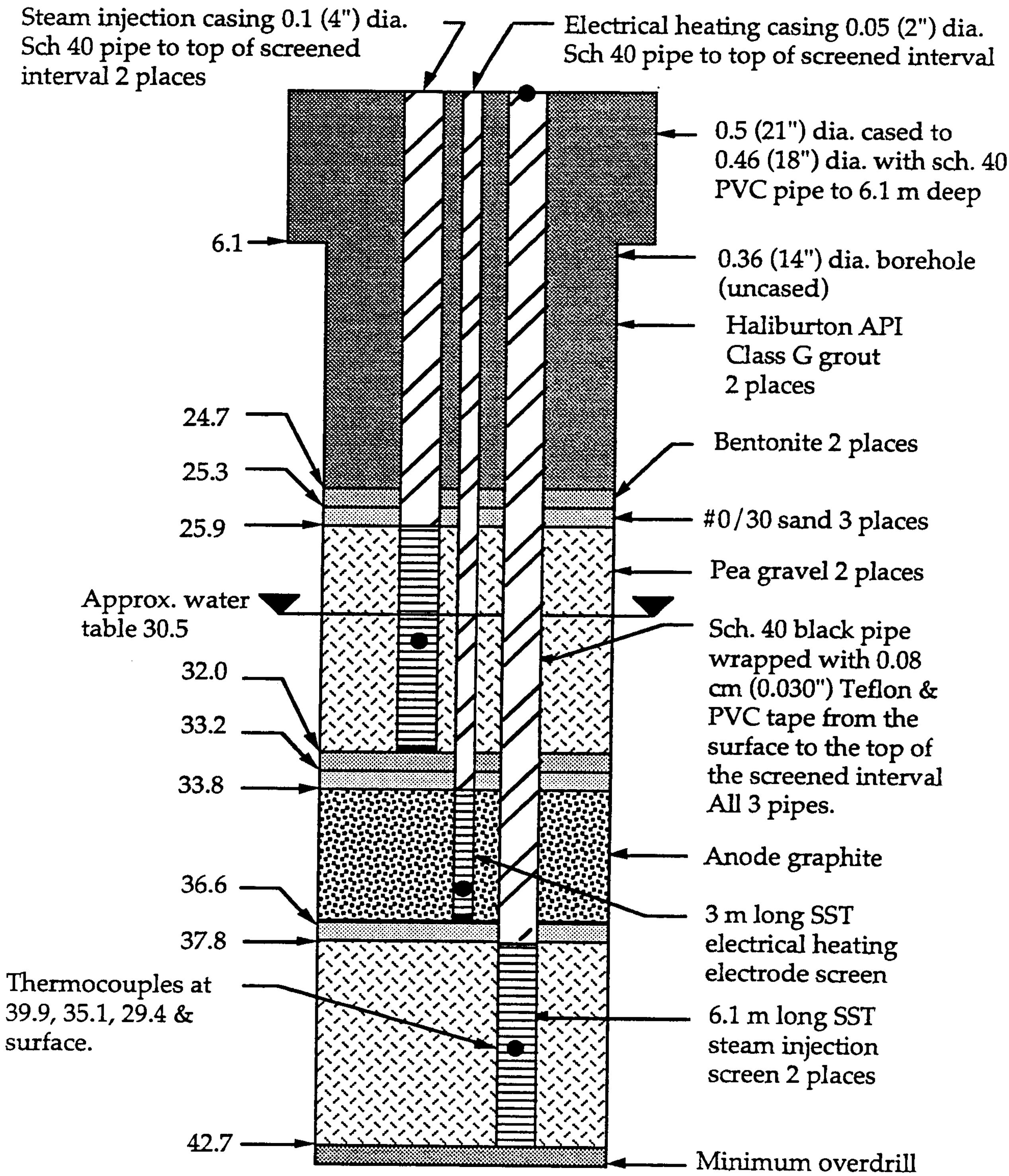
Combination Steam Injection/Electrical Heating Wells

The combination steam injection-electrical heating wells were drilled by the reverse circulation rotary method to a nominal depth of 44.2 meters (145 feet). A typical completion drawing for this well type is shown in Figure 2. Patents are pending for these designs.. Actual depths for the screened intervals are given in Table 2 for all wells. The first 6.1 meters (20 feet) of the wells were drilled to a diameter of 0.53 meters (21 inches). A 0.46 m dia x 0.013 m thick (18" dia. x 0.5" thick) PVC conductor casing was set into the hole and grouted into place. The conductor casing, a necessary part of the drilling operation, also provided additional electrical isolation for the first 6.1 meters (20 feet) of electrical heating casing. The remainder of the hole was drilled to a diameter of 0.36 meters (14 inches) to depth.

Two 0.1 meter IPS (4" IPS) schedule 40 black steel steam injection casings were installed into each well. 6.1 meter (20') long stainless steel screens were located in the upper and lower permeable zones that were identified when the pilot holes were drilled. The screens had 1.02×10^{-3} meter (0.040") slots with 10% open space. A 0.05 meter IPS (2" IPS) electrical heating casing was also installed into each well. The stainless steel screen on the electrical heating casing was installed in the clay layer between the upper and lower permeable zones. All of the black pipe casings above the stainless steel screens were insulated with 7.6×10^{-4} meter (0.060 inch) Teflon over-wrapped with 7.6×10^{-4} meter (0.030 inch) of PVC tape.

The well heads (steam injection and electrical heating) were built from schedule 80 black steel pipe with valves and fittings rated for 2.1×10^{3} kPa (300 Psi) steam. The completed well head assemblies were hydrostatically pressure tested to 1.6×10^{3} kPa (225 Psi), which was 1.5 times the maximum allowable working pressure (MAWP) of the steam system. A venturi was installed into each of the steam well head assemblies to measure steam flow rates. Electrical heating well heads were also pressure tested since they

Figure 2. Typical steam injection / electrical heating well design. (Patent pending)



All depths are typical. Actual depths for each borehole are dependent upon lithologic conditions. Dimensions are in meters unless noted.

Table 2. Screen depths for injection and extraction wells.

Well ID	Well Type	Screen Depth Meters (Feet)
GIW-813	Combination Steam/Elect. Injection	Steam 20.4 to 26.5 (67 to 87) Steam 32.6 to 38.7 (107 to 127) Electrode 27.1 to 30.2 (89 to 99)
GIW-814	Combination Steam/Elect. Injection	Steam 26.4 to 32.5 (86.6 to 106.5) Steam 36.9 to 43 (121 to 141) Electrode 33.5 to 36.6 (110 to 120)
GIW-815	Combination Steam/Elect. Injection	Steam 23.5 to 29.6 (77 to 97) Steam 34.3 to 40.4 (112.5 to 132.5) Electrode 31.1 to 34.1 (102 to 112)
GIW-818	Combination Steam/Elect. Injection	Steam 25 to 31.1 (82 to 102) Steam 36.6 to 42.7 (120 to 140) Electrode 33.5 to 36.6 (110 to 120)
GIW-819	Combination Steam/Elect. Injection	Steam 24 to 30.1 (78.6 to 98.6) Steam 36.9 to 43 (121 to 141) Electrode 32.9 to 36 (108 to 118)
GIW-820	Steam Injection Only	Steam 25.9 to 32 (85 to 105) Steam 34.1 to 40.2 (112 to 132)
HW-001	Electrical Heating Only	Electrode 20.4 to 23.4 (67 to 77) Electrode 31.4 to 34.4 (103 to 113)
HW-002	Electrical Heating Only	Electrode 20.7 to 23.8 (68 to 78) Electrode 32.6 to 35.7 (107 to 117)
HW-003	Electrical Heating Only	Electrode 20.3 to 23.3 (66.5 to 76.5) Electrode 33.2 to 36.3 (109 to 119)
GEW-808	Extraction	15.2 to 42.7 (50 to 140)
GEW-816	Extraction	15.2 to 42.7 (50 to 140)

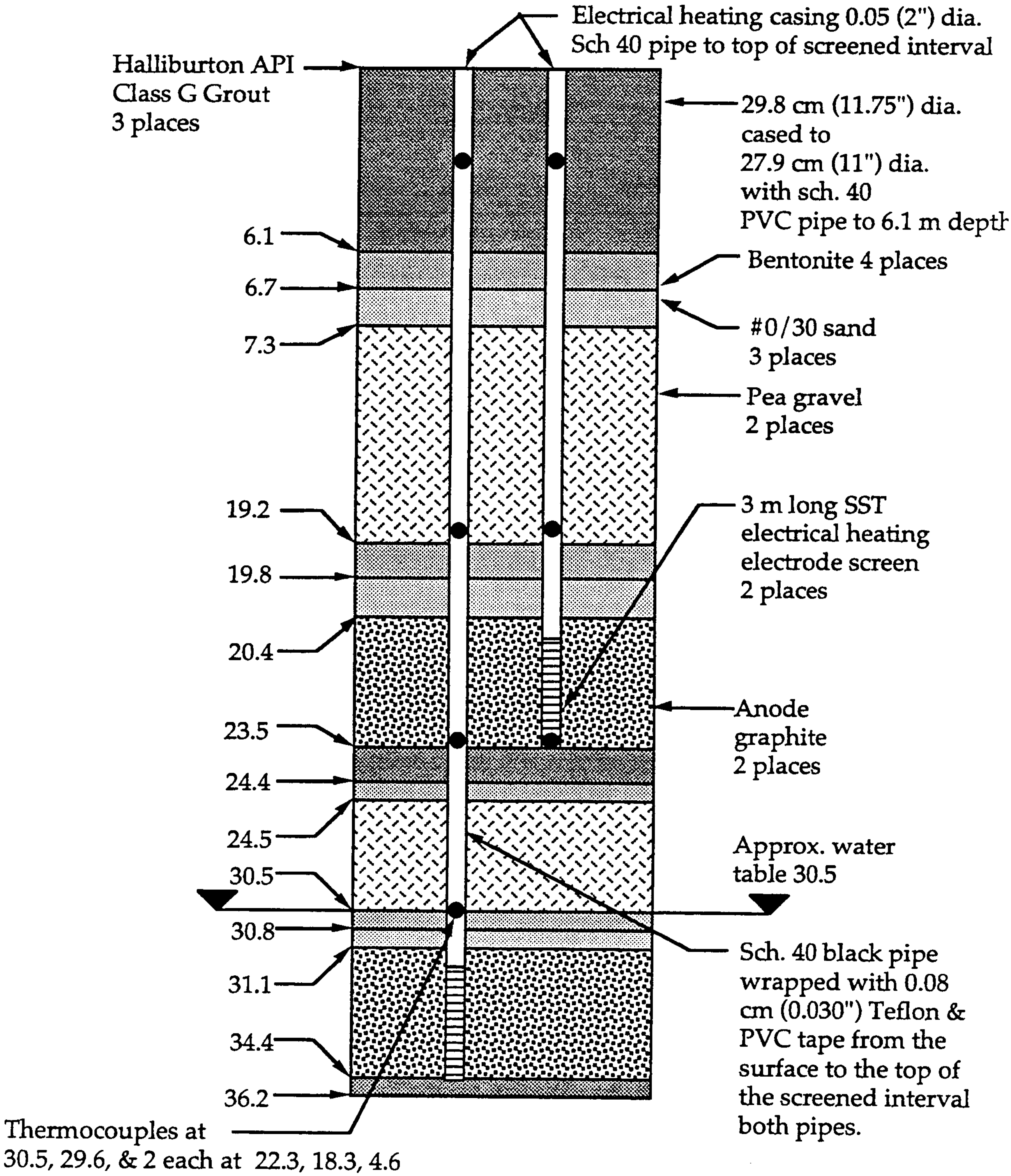
could become pressurized from subsurface injected steam. Completion materials in the bore-holes consisted of:

6.4×10^{-3} meter (0.25") diameter pea gravel around the steam injection screens,

6.4×10^{-3} meter (0.25") diameter anode graphite around the electrical heating screen, and Haliburton API Class G grout above the uppermost steam injection screen to the surface.

Anode graphite was used around the electrode screened intervals to increase conductivity into the formation. Fine sand and bentonite plugs were placed between the screened sections of each casing above the water table to prevent communication between screens. Below the water table, only fine sand was used as plug material between screens. The steam injection-only well was completed exactly the same as the combination wells except that the electrical heating casing and graphite completion material were not included.

Figure 3. Electric heating well design (Patent pending).



All depths are nominal. Actual depths for each borehole are dependent upon lithologic conditions. Dimensions are in meters unless noted.

Electrical Heating-Only Wells

Electrical heating only wells were drilled with an hollow stem auger to a nominal depth of 36.6 meters (120') and 0.3 meters (11") in diameter. A drawing of the electrical heating wells is shown in Figure 3. These wells were drilled closer to the center of the gasoline plume. Two electrical heating casings were placed into each well. Screened intervals targeted the clay layer between permeable zones, similar to the perimeter wells, as well as the clays above.

Electrical heating casings were identical to the casings installed in the perimeter wells. The riser above the stainless steel screen was insulated with 7.6 x 10^{-4} meter (0.060 inches) of Teflon over-wrapped by 7.6 x 10^{-4} meter (0.030 inches) of PVC tape. Anode graphite completion material was used around the screens Plugs were installed above and below the upper electrode, and above the lower electrode to prevent communication between casings. A sand/bentonite plug was also installed at the base of the upper grout plug.

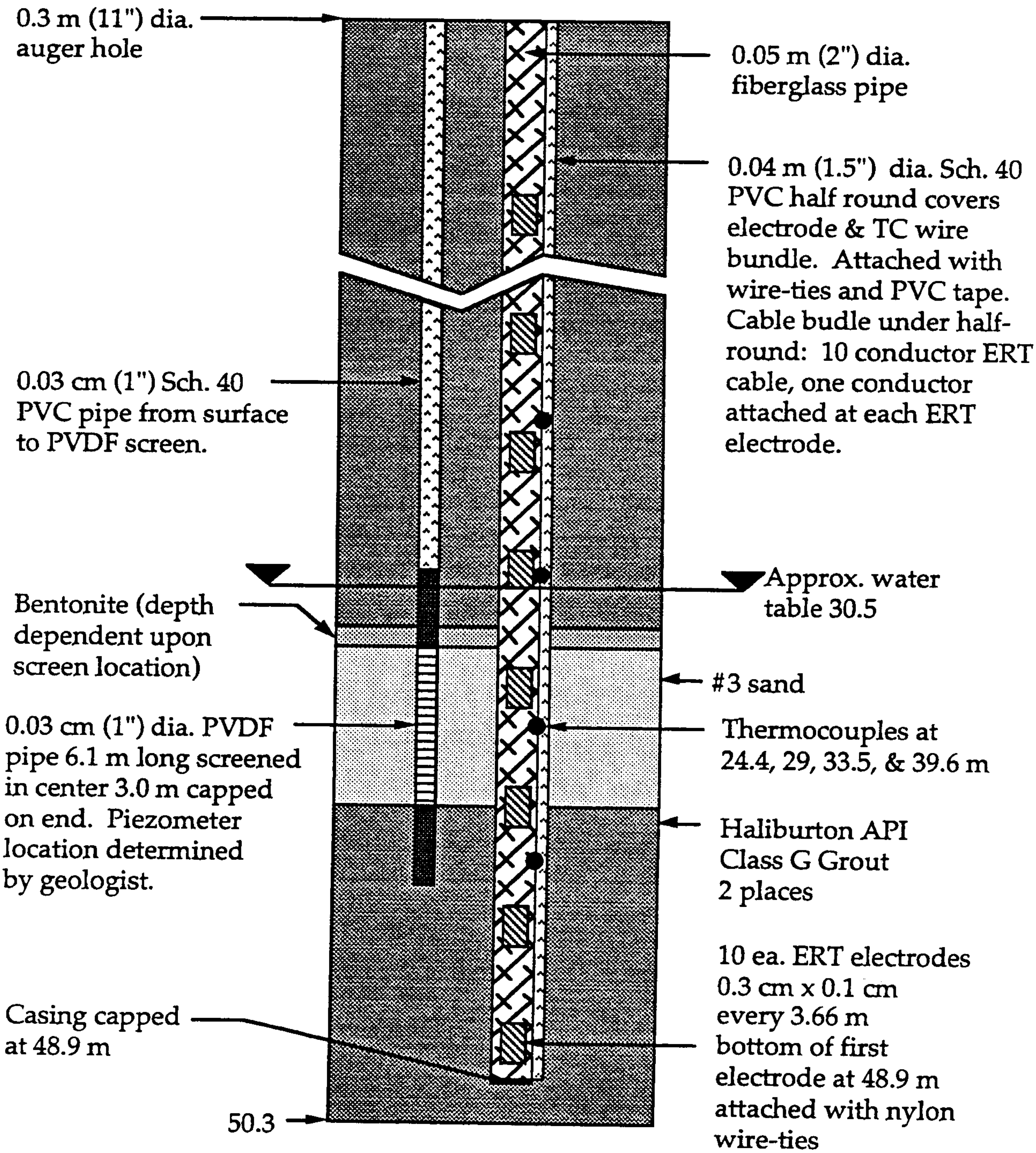
Monitoring Wells

Combination monitoring wells were designed to accommodate Electrical Resistance Tomography (ERT), temperature instrumentation and conventional geophysical logging. The combination monitoring wells were drilled with a hollow stem auger rig. The eleven holes were drilled to a depth of 50.3 meters (165 feet) and a diameter of 0.23 meters (11 inches). 0.05 meter (2 inch) fiberglass pipe, rated at 107 °C (225 °F), was used for the well casing. Metal casing materials could not be used in these wells because it would have interfered with ERT measurements. In six wells, piezometer casings were installed. Piezometers were of 3.05 m (10 foot) long by 0.03 meter (1 inch) diameter schedule 40 PVDF pipe, screened in the aquifer. The piezometers were capped on the end and had risers of 0.03 meter (1 inch) PVC schedule 40 pipe to the surface. The casings were grouted into the wells from bottom of the well to the surface with Haliburton API Class G grout except in the region of the piezometer screen. Number 3 sand was used around the screened sections. Figure4 shows the well completion details.

ERT electrodes were attached with stainless steel tie wraps to the exterior surface of the fiberglass casing. Ten electrodes were attached to each casing spaced at 3.7 meter (12 foot) intervals. The electrodes themselves were made from 0.3 m x 0.1 m x 1.5x10^{-3} m (12″ x 4″ x 0.060″) stainless steel, curved to match the outside radius of the casing. A shielded 12 conductor cable was used to connect the electrodes to the surface (2 wires were unused). Fixed thermocouples were installed at 24.4, 29, 33.5, and 39.6 meters (80, 95, 110, and 130 feet). The electrical and thermocouple wires were covered by a half round of 0.03 meter (1 inch) diameter schedule 40 PVC pipe to protect it during installation into the borehole. The cable and PVC cover were tie wrapped to the fiberglass casing to hold it in place during installation.

Continuous temperature profiles of the formation were made by running a temperature probe down the inside of the casing to depth. The fixed thermocouples were used to provide

Figure 4. ERT imaging/temperature well design (Patent pending).



Dimensions in meters unless noted.
Not To Scale.

fixed temperature data and to calibrate the probe measurements.

Tiltmeter Boreholes

A total of 17 tiltmeter stations were installed around the site. They were used in conjunction with temperature logs and ERT images to map the location and radial extent of the steam front. The holes were 0.35 meters in diameter by 6.1 meters deep (14" x 20') and drilled with an auger rig. The wells were cased with 0.2 meter diameter (8") PVC irrigation pipe. The first casing that was installed was grouted in one lift. Unfortunately, the relatively thin-walled PVC casing collapsed due to the external pressure of the grout as it was poured into the annulus. Subsequent wells were grouted in multiple lifts to prevent collapse. The tiltmeters were installed into the casings at a depth of approximately 3.05 to 4.6 meters (10' to 15'). The casings were then filled with sand. Figure 5 shows the details of the well completion.

Extraction Wells

The two extraction wells were drilled by the reverse circulation rotary method to a nominal depth of 47.2 meters (155') and a diameter of 0.36 meters (14"). 0.2 meter (8") casings were installed into these wells. The casings were screened from 15.2 to 42.7 meters (50' to 140') deep. The stainless steel screens had 1.02×10^{-3} meter (0.040") slots with 10% open space. The upper 15.2 meters (50') of casing was fiberglass pipe. Fiberglass was selected to provide electrical isolation from the formation during electrical heating.

The well heads for the extraction wells were built from stainless steel. The wells were designed to remove liquid and vapor; they were capable of pumping liquid to the surface and simultaneous vapor extraction. Even though the extraction wells were intended to be under vacuum only, the possibility existed that they could be pressurized by steam. Therefore they were hydrostatically pressure tested to 1.6×10^3 kPa (225 Psi) before they were installed onto the wells.

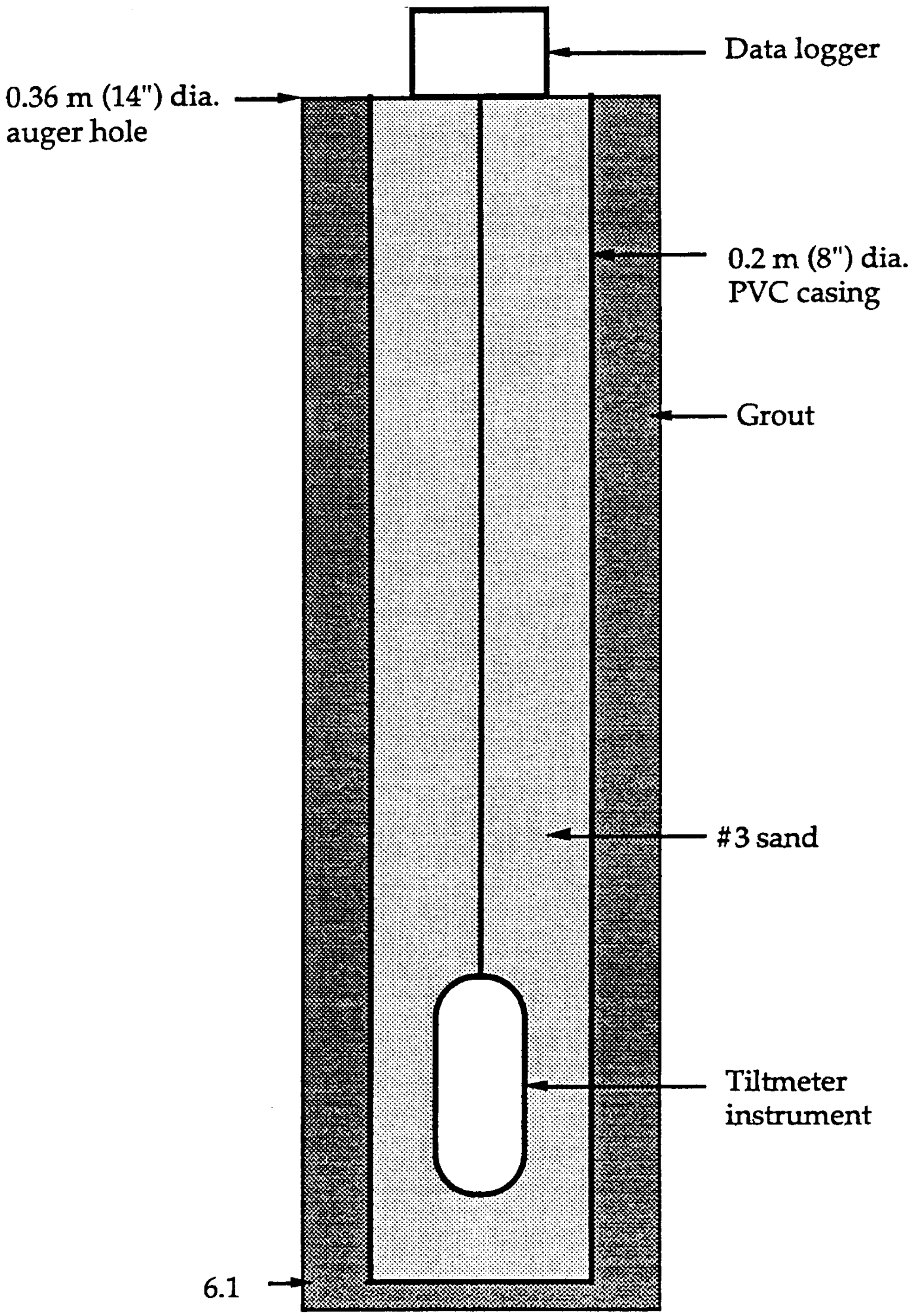
Pneumatic pumps were used to extract water and free product from the wells during operations. Pneumatic pumps were selected to reduce or eliminate emulsification of the pumped effluent stream. However, there was significant emulsification of the liquid stream because of boiling in and near the borehole. An extraction well drawing is shown in Figure 6.

Electrical Heating

Electrical Heating Operational Strategy

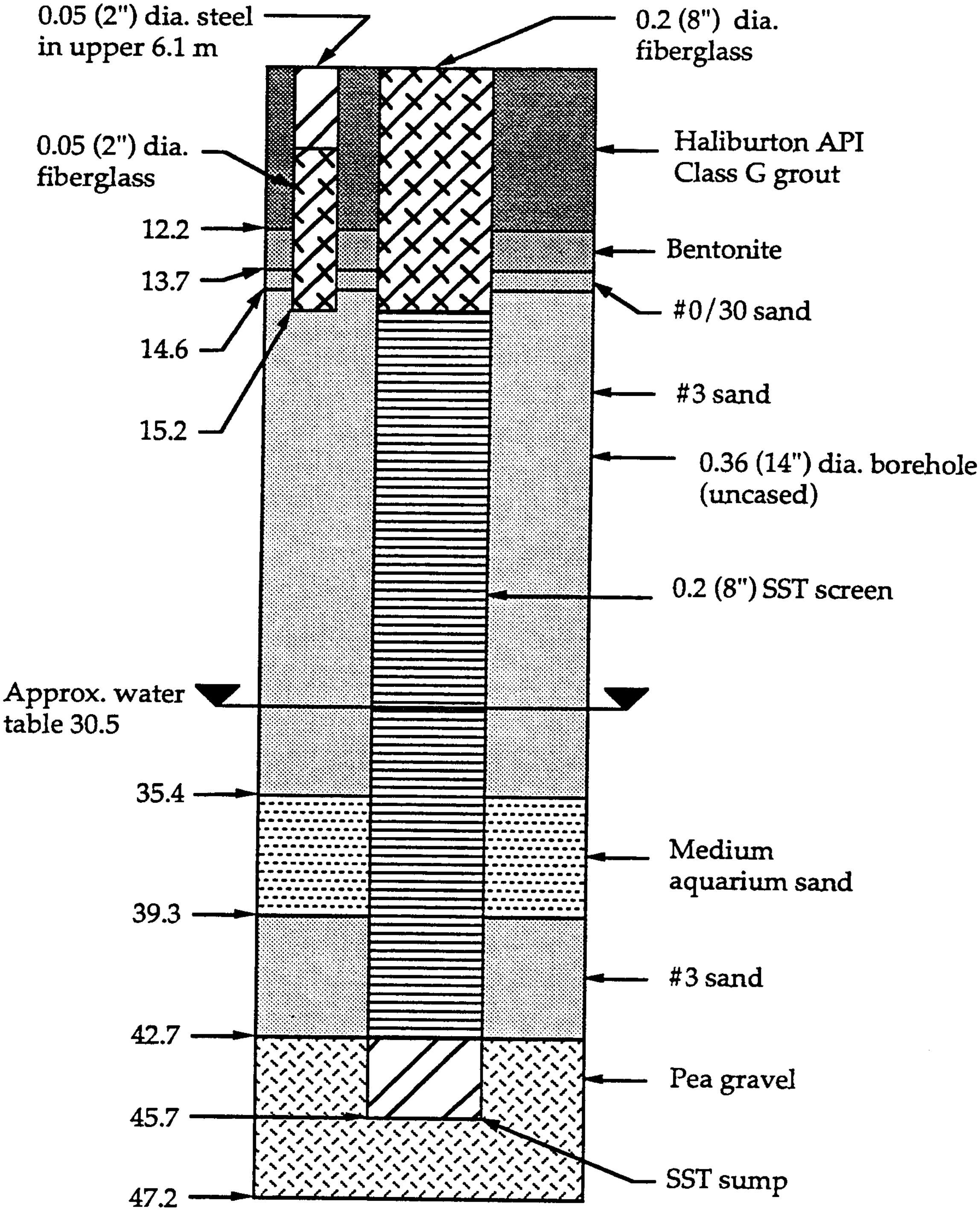
Electrical heating is used to heat the tight clay rich zones that steam does not easily penetrate. The clays are more electrically conductive than the permeable zones at ambient temperature, permitting the channeling of electrical energy into the desired areas. However, this contrast is diminished when the permeable zones are heated by steam. An electrical preheat of the clay-rich zones increases their conductivity sufficiently to ensure an adequate electrical contrast during steam injection. This will prevent inefficient dissipation of electrical energy throughout the formation instead of just the targeted clay zones. Therefore, an electrical preheat is performed prior to steaming.

Figure 5. Tiltmeter well design.



Dimensions in meters unless noted.
Not To Scale.

Figure 6. Extraction well design.



Dimensions in meters unless noted.

Description of Electrical Heating Surface Equipment

Electrical power was supplied from the utility grid at the Laboratory. Portable, truck mounted generators were considered, but could not be used because of local air district regulations regarding air emissions.

The major surface electrical equipment shown in Figure 7 consisted of:

- a 15 kV load interrupter switch;
- a 13.8kV/1500KVA 3 phase transformer with selectable secondary taps at 208, 350, 480 and 600volts;
- a main circuit breaker rated at 4000 Amps at 600VAC, and a 4000 Amp, 600 VAC switch panel.

Electrical Heating Safety Considerations

A fence was constructed around the remediation area to control access into the area during electrical heating. During this phase of the operation, personnel were not allowed inside the fenced area due to the possibility of electrical shock. As a further precaution, electrical heating was conducted only during the night to minimize the number of people in the immediate vicinity. Gates into the area were interlocked so that if opened while the system was energized, the power would be automatically shut off.

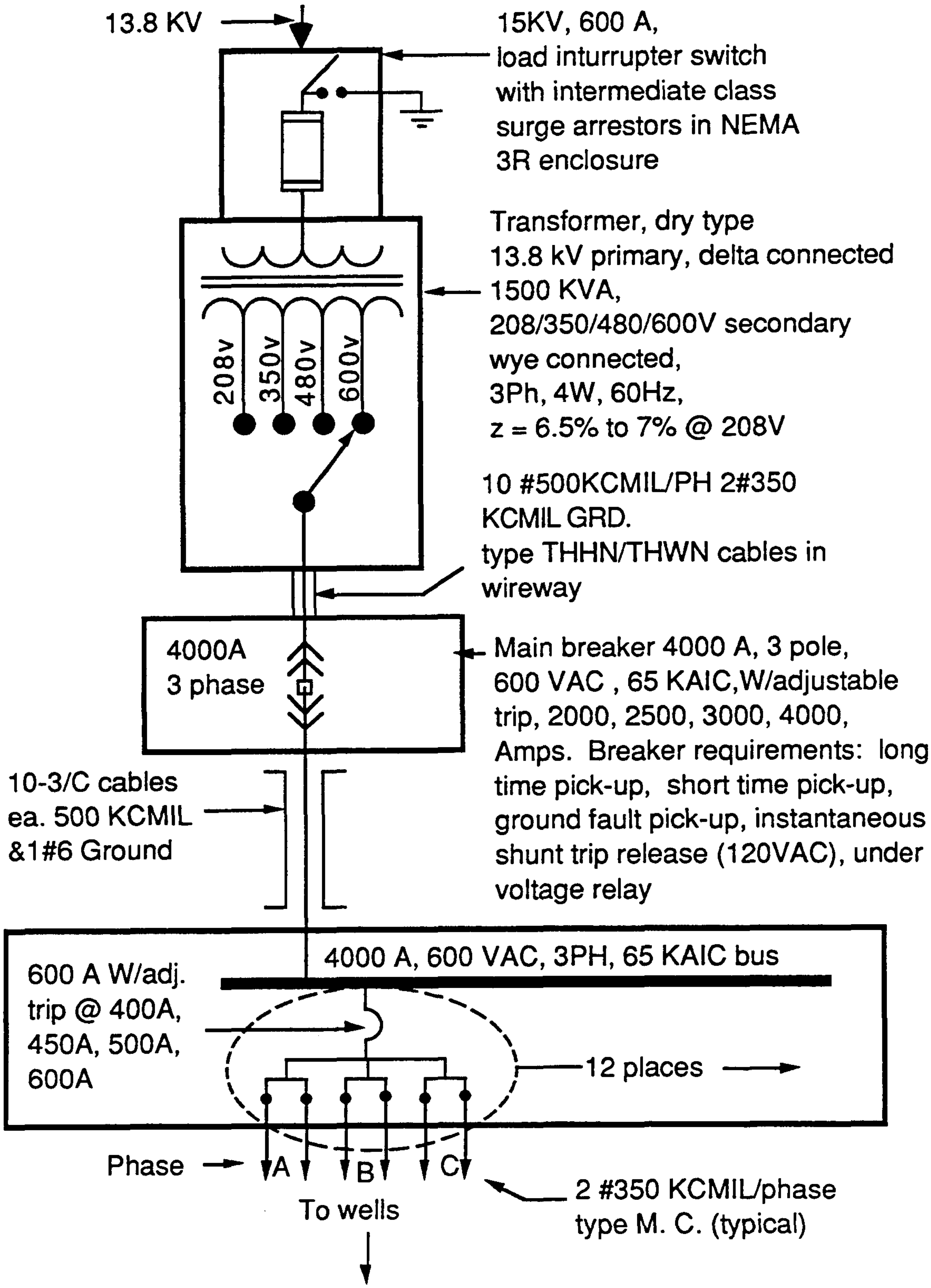
Our operational safety procedures (see Appendix B) required that potential differences between ground and surface equipment located outside the fenced area be less than 10 VAC. We never measured over 5 volts outside the fence during electrical heating even at an applied potential of 600 volts. Our perimeter electrodes were as close as 2.4 meters (8') from the fence in two instances.

Electrical Heating Operations

Electrical heating operations began in November of 1993 and lasted for approximately 8 weeks. 202,000 kilowatt hours of electrical energy were deposited into the formation. Electrical heating began with the transformer at the lowest secondary tap setting of 208 volts and gradually ramped up to 600 volts over the 8 week period.

To reduce the possibility of damaging the electrodes by overheating currents were limited to 300 to 400 Amps per electrode . During electrical heating operations as part of the Clean Site Engineering Demonstration we discovered that the amount of current each electrode would draw was directly affected by the moisture content of the soil surrounding the electrode. As heating continued and the borehole around the electrode dried, the amperage dropped because of the reduced electrical conductivity of the soil. The multiple secondary taps on the transformer gave us the ability to the increase the potential and thus the current into the electrodes. Eventually it became necessary to wet the wells with water from the surface to maintain current flow into the formation. Wells at the same phase were supplied continuously by water from common reservoirs. The wells were gravity fed from the reservoirs at the rate of 4 to 11 liters per minute (1 to 3 gallons per minute). The reservoirs we used

Figure 7. Electrical heating surface equipment.



were large enough to keep the wells wet for approximately 2 hours. When the water supply was exhausted, we shut off power, refilled the reservoirs, and began electrical heating again.

The type T thermocouples installed on the heating electrodes did not perform as intended. The thermocouples were installed onto the electrodes and wired back to a central data logger. We intended to monitor the electrode temperatures real-time during electrical heating, however, the thermocouple signals were very noisy because of induced current caused by the electrical heating power. Two thermocouple data logger cards were damaged by over voltage during electrical heating. As a result, all of the electrical heating well thermocouples were disconnected from the data logger to prevent further damage to the data acquisition system. The inability to monitor the temperature while the electrodes were energized resulted in damaged electrodes. The electrode temperatures rose much higher than anticipated. Before being disconnected, several electrode thermocouples indicated extremely high temperatures (>1,000 °C), but the accuracy of the measurements was in question due to the extreme fluctuations during heating. Several stainless steel electrode screens were partially or entirely melted. The inability to maintain nominal current levels in several other electrodes led us to believe that others were damaged to some extent. In one combination steam injection-electrical heating well (GIW-819 Deep) the steam injection casing may have been damaged by the heating electrode adjacent to it. The injection casing was tagged and found to be obstructed at the depth of the heating electrode, suggesting that it may have been melted.

Another problem we encountered with the electrical heating wells was sloughing of completion materials away from the electrode, decoupling it from the formation. This was confirmed when we used a downhole camera to diagnose the poor performance of one of the electrodes. Not only had the lower portion of an electrode melted off, but a substantial cavity existed around what remained of the electrode.

Steam Injection

Description of Steam Injection Surface Equipment

Steam was generated by a 33.8×10^9J/h (32×10^6 Btu/h) boiler that was capable of producing about 12,700 kg/h (28,000 Lbm/h) of steam to the wells. We would have preferred to use a larger capacity boiler, however, we were limited to the smaller unit because of air emissions restrictions imposed by the Bay Area Air Quality Management District. We were required to use Best Available Control Technology (BACT), including flue gas recirculation, to reduce NO_x emissions to less than 30PPM.

The boiler was capable of producing steam at 2.1 mPa (300 Psi), but for our purposes was not operated above 0.9mPa (135 Psi). The maximum allowable working pressure (MAWP) of the steam distribution system to the wells was 1.05 mPa (150 Psi). The two northernmost wells (GIW-818 and 820) were supplied by a single pressure-regulated manifold. The remaining four wells were supplied by a separate pressure-regulated manifold. The manifolds consisted of 0.15 meter (6") IPS schedule 40 welded black steel pipe. Flexible steam hose rated at 1.7 mPa (250 Psi) and 382 °C (400 °F) carried steam between the manifold and well heads.

Each steam well head was equipped with a venturi and differential pressure transducer to measure steam flow rate. The transducers were wired back to the central data logger and from there the data were down loaded to a computer. Injection rates were monitored continuously during operations. The rate of steam injection into each well was controlled by globe valves on each well head. Injection pressures were limited to 11.3 kPa/m (0.5 Psi/ft) of overburden to prevent fracturing of the formation. With one exception, injection pressures on the gasoline spill site were limited to no more than 379 kPa (55 Psi) for the deep injection intervals, and 310 kPa (45Psi) for the shallow intervals . The exception to the 11.3 kPa/m (0.5 Psi/ft) limit involved injection well GIW-819. The deep injection casing of well GIW-819, with a screen depth of 36.9 m to 43 m (121' to 141'), was damaged during electrical heating. The casing was blocked and possibly melted off by the adjacent electrical heating electrode at 32.9 m to 36 m (108' to 118'). In an unsuccessful attempt to clear the blockage, we deliberately over pressured the well to 690 kPa (100 Psi). The test was conducted for approximately 1 hour and resulted in no change in the condition of the casing, any signs of hydrofracture of the formation, or steam breakthrough at the surface.

Steam Injection Strategy: Pass One First pass steam injection began on February 4, 1993 and lasted for 40 days. Steam was injected into the lower zones first, displacing the ground water and some free product gasoline towards the extraction wells. After 12 days of injection, the shallow injection wells were also brought on line. Table 3 summarizes the injection schedule for each well. Water and vapor were extracted continuously during the first steam pass.

During the first 40 days of steam injection approximately 6.4 m^3 (1,700 gallons) of gasoline were removed. Plots of steam injection rates into all of the wells are shown in Figures 8 and 9. Appendix A contains detailed plots of injection rates and cumulative steam injected for each individual well.

Plots of extracted vapor and liquid temperature are shown in Figures 10 and 11. The abrupt rise in vapor temperature after ten days of steam injection is an indication of steam breakthrough into the extraction well. A subsequent decline in temperature is observed when the steam injection interval is shifted from the lower zones to the upper zones. Steam breakthrough occurred again at about 18 days after injection began. Liquid effluent temperatures began rising within 3 days of the beginning of steam injection as shown in Figure 11 and remained high throughout the first pass.

Table 3. Steam Injection History for the First Pass

Month ⇨		February, 1993																										March, 1993													
Date ⇨		3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28	1	2	3	4	5	6	7	8	9	10	11	12	13	14
	U															■	■	■	■	■	■	■	■	■	■	■	■	■	■	■	■										
GIW-813	L			■	■	■	■	■	■	■	■	■	■	■	■	■	■	■	■	■	■	■	■	■	■						■	■	■	■	■	■	■	■	■		
	U															■	■	■	■	■	■	■	■	■	■	■	■	■	■	■	■										
GIW-814	L			■	■	■	■	■	■	■	■	■	■	■	■	■	■	■	■	■	■	■	■	■	■						■	■	■	■	■	■	■	■	■		
	U															■	■	■	■	■	■	■	■	■	■	■	■	■	■	■	■										
GIW-815	L			■	■	■	■	■	■	■	■	■	■	■	■	■	■	■	■	■	■	■	■	■	■						■	■	■	■	■	■	■	■	■		
	U															■	■	■	■	■	■	■	■	■	■	■	■	■	■	■	■										
GIW-818	L			■	■	■	■	■	■	■	■	■	■	■	■	■	■	■	■	■	■	■	■	■	■						■	■	■	■	■	■	■	■	■		
	U															■	■	■	■	■	■	■	■	■	■	■	■	■	■	■	■										
GIW-819	L			■	■	■	■	■	■	■	■	■	■	■	■	■	■	■	■	■	■	■	■	■	■						■	■	■	■	■	■	■	■	■		
	U															■	■	■	■	■	■	■	■	■	■	■	■	■	■	■	■										
GIW-820	L			■	■	■	■	■	■	■	■	■	■	■	■	■	■	■	■	■	■	■	■	■	■						■	■	■	■	■	■	■	■	■		
Days from Zero Time ⇨		0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30	31	32	33	34	35	36	37	38	39

Figure 8a. Steam injection rates into the upper screened intervals of wells GIW-813, 814, and 815 during the first injection pass.

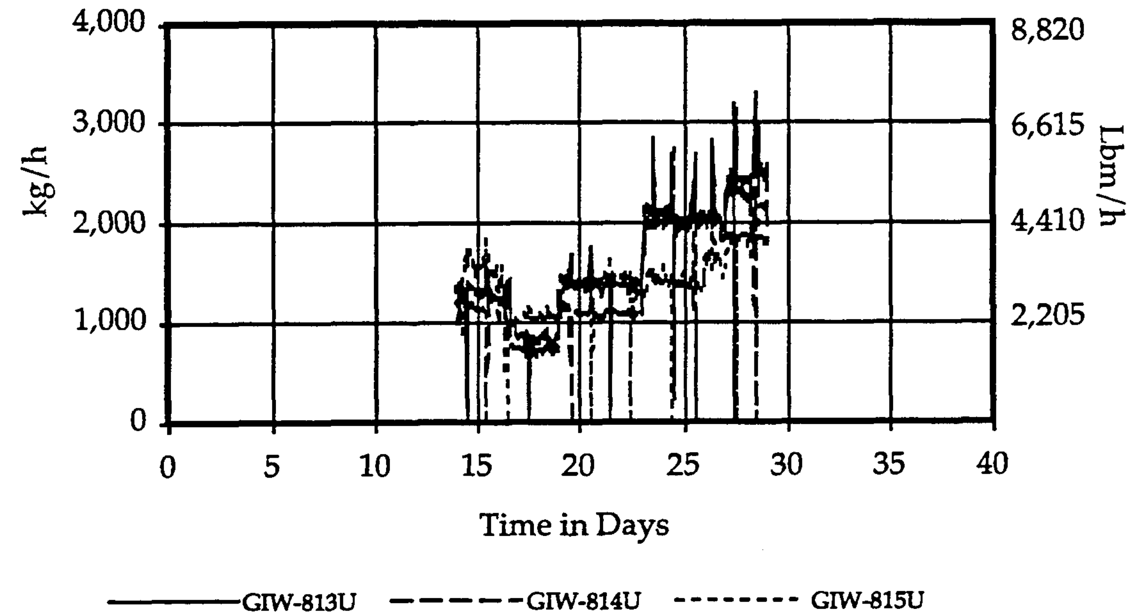


Figure 8b. Steam injection rates into the upper screened intervals of wells GIW-818, 819, and 820 during the first injection pass.

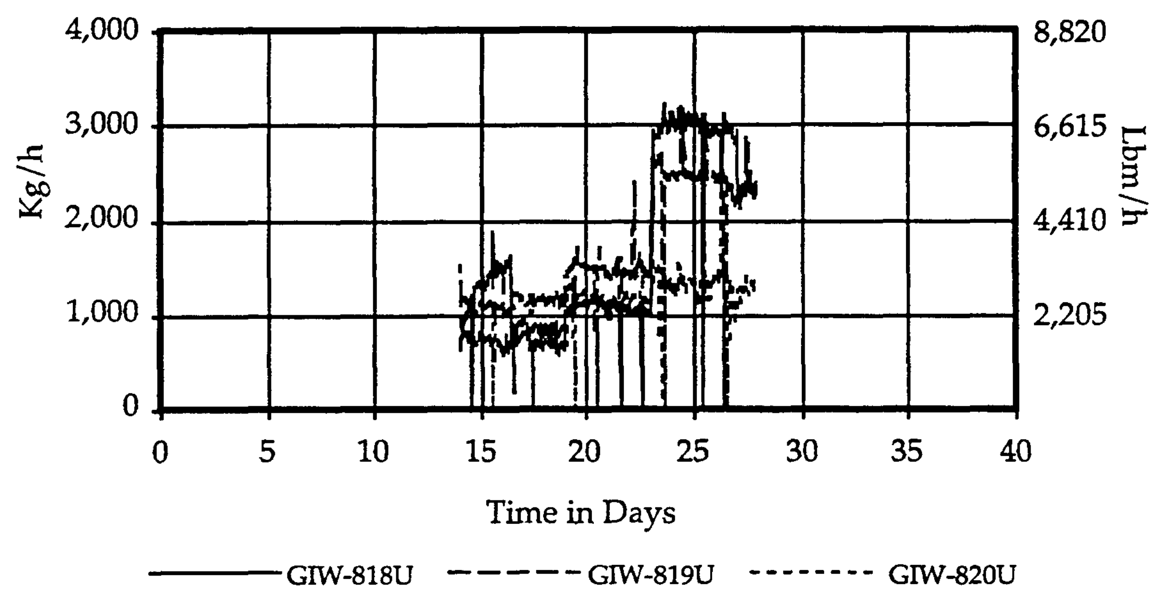


Figure 9a. Steam injection rates into the lower screened intervals of wells GIW-813, 814, and 815 during the first injection pass.

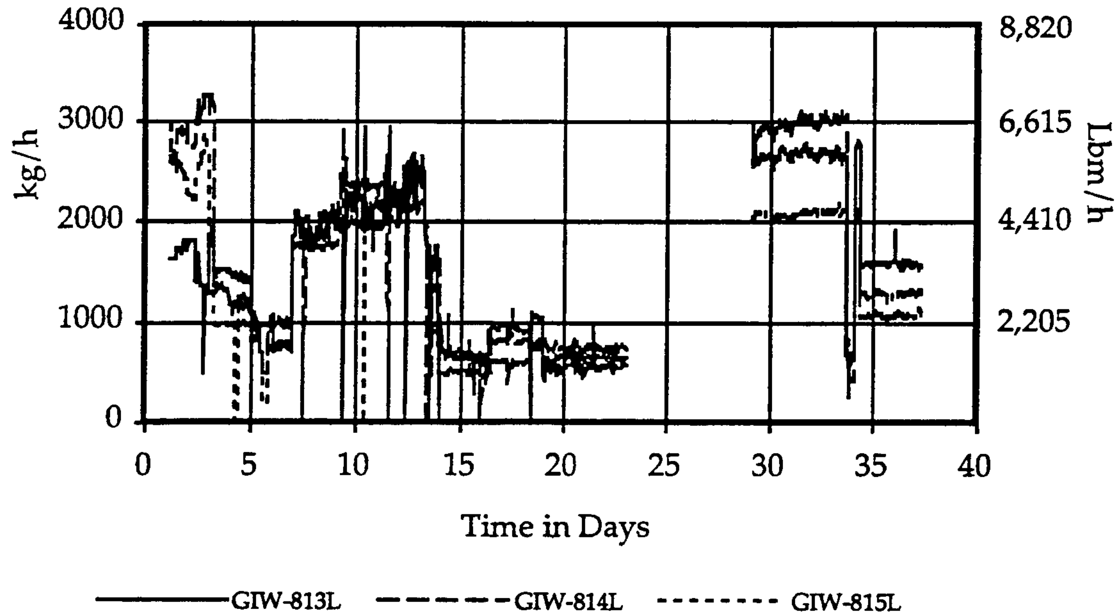


Figure 9b. Steam injection rates into the lower screened intervals of wells GIW-818, 819, and 820 during the first injection pass.

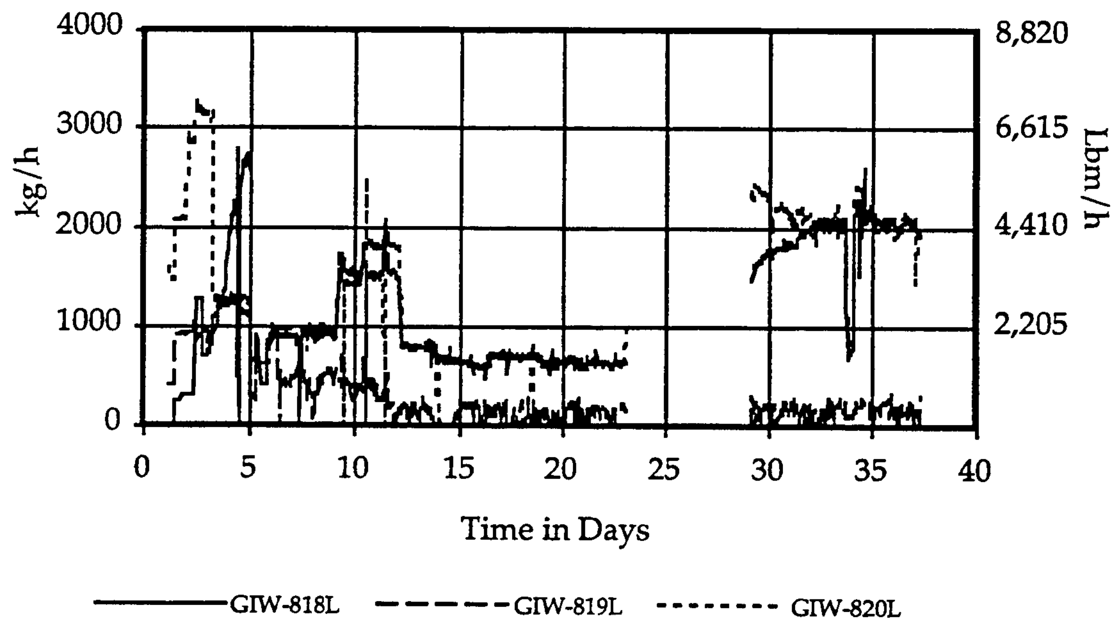


Figure 10. Extraction well vapor temperatures during the first pass.

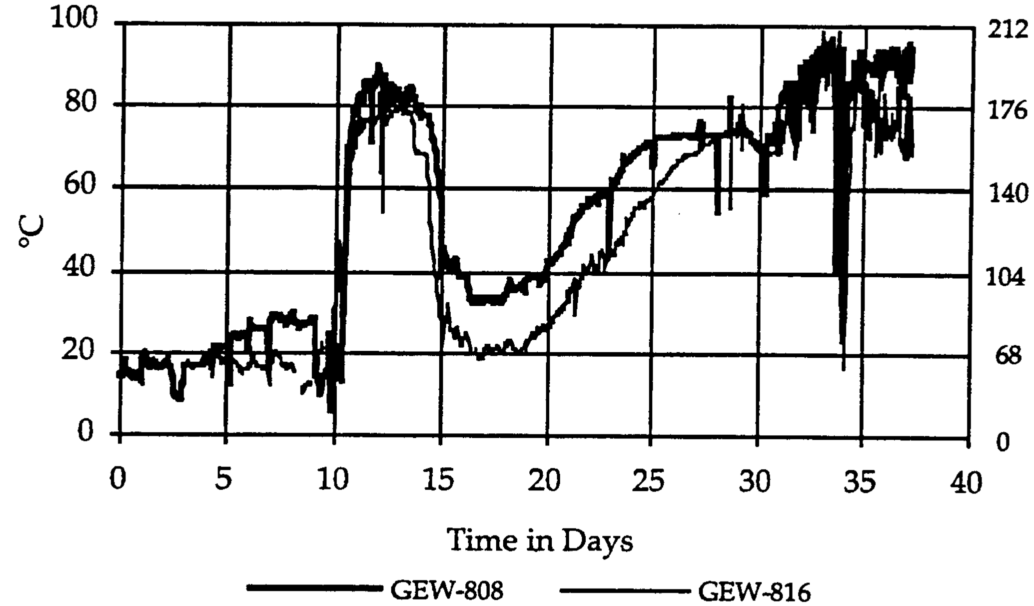
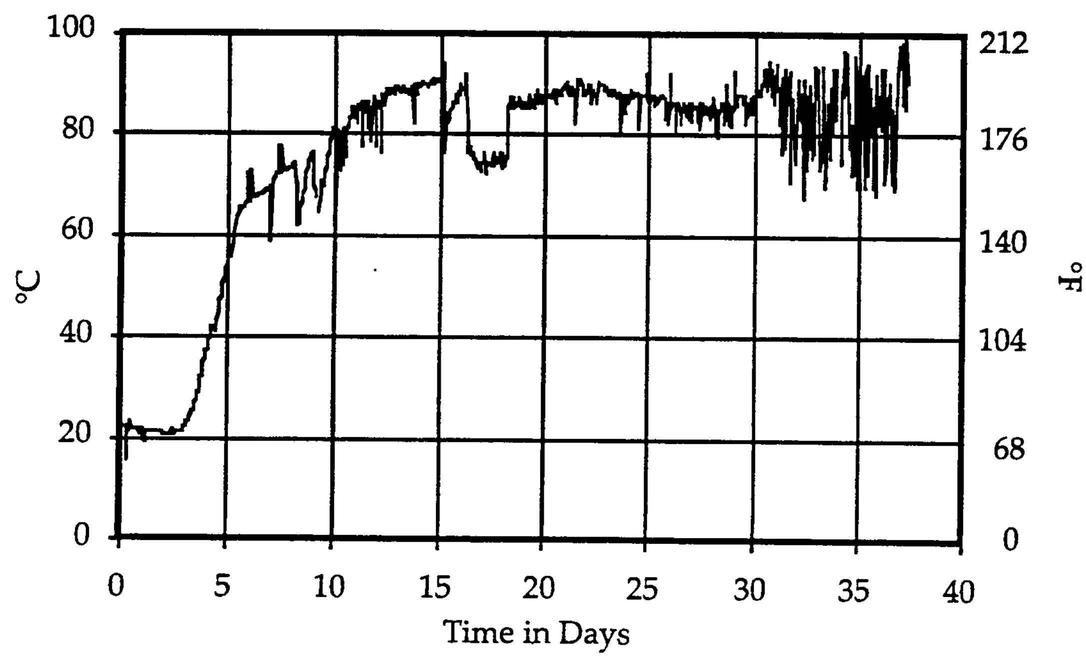


Figure 11. Effluent liquid temperature during the first pass.



Steam Injection Strategy: Pass Two During the second pass steam was injected for 22 days over a 38 day period. (We were restricted by the Bay Area Air Quality Management District to no more than a cumulative total of 60 days of boiler run time for the first and second passes). The strategy employed during the second pass differed from the first. The goal was to optimize the amount of time the treatment area was kept heated and under vacuum. We began by injecting into the lower steam zone for five days, followed by five days of injection into the upper zones. The intent was to dewater and heat the upper permeable zone and to displace the water from the lower zone so that vacuum could be applied to the formation. At the end of the first ten day period, steam injection was stopped and remained off for five days. Liquid and vacuum extraction continued throughout the entire second pass. Additional cycles of steam on-steam off were conducted to a total of 22 days of steam injection. Table 4 shows the injection times for each individual well.

Thermally enhanced vacuum venting increased the extraction rates of vapor phase gasoline substantially during the periods of no steam injection. A total of 18,550 liters (4,900 gallons) of gasoline were removed during the second pass. Peak extraction rates greater than 950 liters (250 gallons) of gasoline per day were achieved. The average extraction rate for the 40 day cycle was 475 liters (125 gallons) per day. During the second pass, we placed greater emphasis upon controlling the direction and extent of the steam front. Cool spots in the formation were detected by Electrical Resistance Tomography (ERT) images. When a cool spot was detected, we made an effort to direct steam to the area by injecting into only selected wells or by adjusting the injection rates into multiple wells. This was a successful tactic for addressing problem areas.

Steam injection rates for all of the injection wells are shown in Figures 12 and 13. More detailed plots for individual wells are presented in the Appendix. Vapor and liquid extraction data from the second pass are shown in Figures 14 and 15. During the steam injection operation, we "shut in" or valved off individual wells for one hour periods to introduce pressure transients into the ground water reservoir. These transients were detected by the tiltmeter array surrounding the site and the data used to plot the location of the steam front emanating from each well. The spikes in the injection rate curves that drop to zero are an indication of a well shut in.

Control of the steam front was accomplished by varying the steam injection rate into each well. Rates were reduced to control the outward movement of steam away from the central extraction wells or increased to concentrate steam into suspected cool spots. The decision to increase or decrease the injection rate into a particular well was based upon the fixed thermocouples in the field, the continuous temperature logs taken in the temperature wells, tiltmeter data and ERT images.

Table 4. Steam Injection History for the Second Pass

Month		May, 1993									June, 1993																													
Date		23	24	25	26	27	28	29	30	31	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30
GIW-813	U																				■																■	■	■	■
	L																									■	■	■	■	■	■						■	■	■	■
GIW-814	U																	■	■	■	■	■													■	■	■	■	■	■
	L																										■	■	■	■	■				■	■	■	■	■	■
GIW-815	U																■	■	■	■	■	■																		
	L											■	■	■	■	■	■													■	■								■	■
GIW-818	U																		■	■	■	■																		
	L															■	■									■	■	■	■	■	■								■	■
GIW-819	U																		■	■	■																		■	■
	L																																						■	■
GIW-820	U																■	■	■	■	■	■																		
	L											■	■	■	■	■	■											■	■	■	■								■	■
Days from Zero Time		0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30	31	32	33	34	35	36	37	38

Figure 12a. Steam injection rates into the upper screened intervals of wells GIW-813, 814, and 815 during the second injection pass.

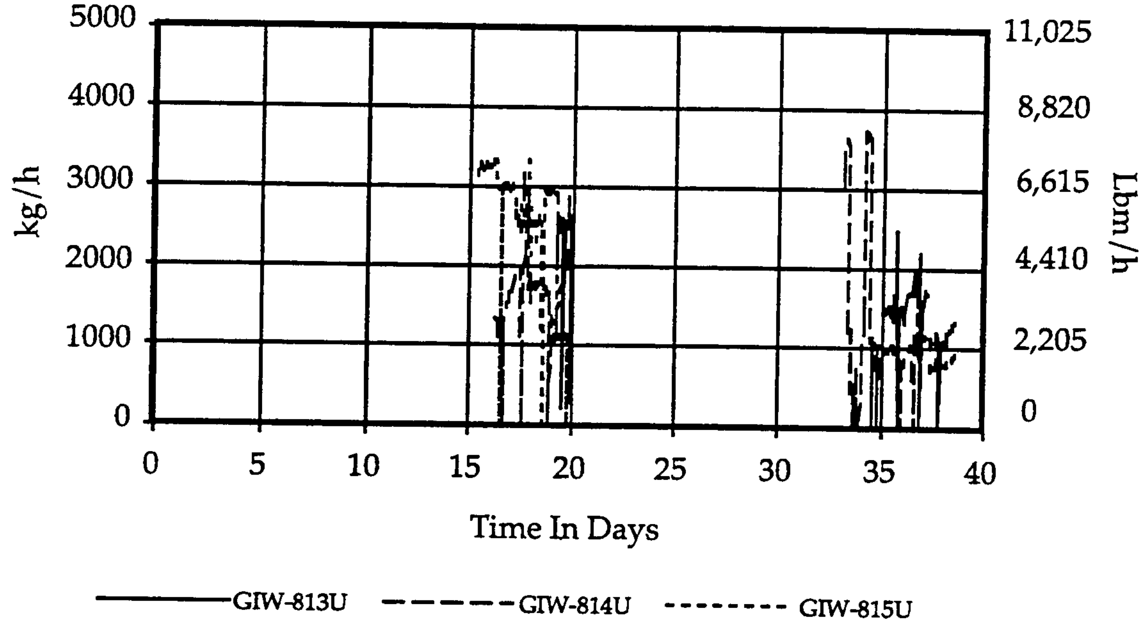


Figure 12b. Steam injection rates into the upper screened intervals of wells GIW-818, 819, and 820 during the second injection pass.

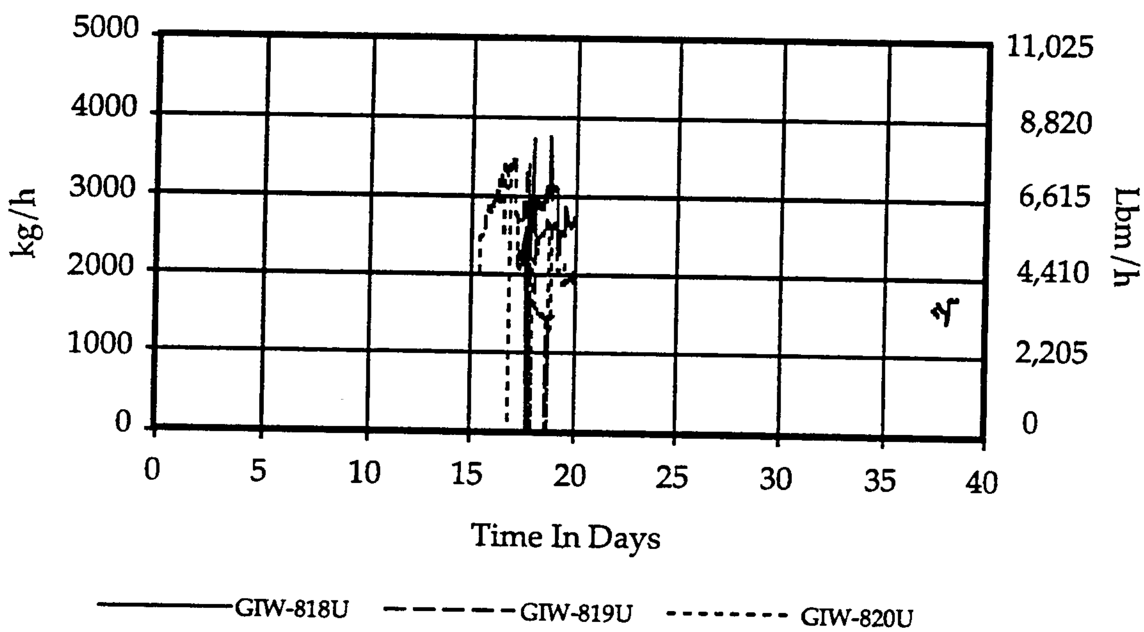


Figure 13a. Steam injection rates into the lower screened intervals for wells GIW-813, 814, and 815 during the second injection pass.

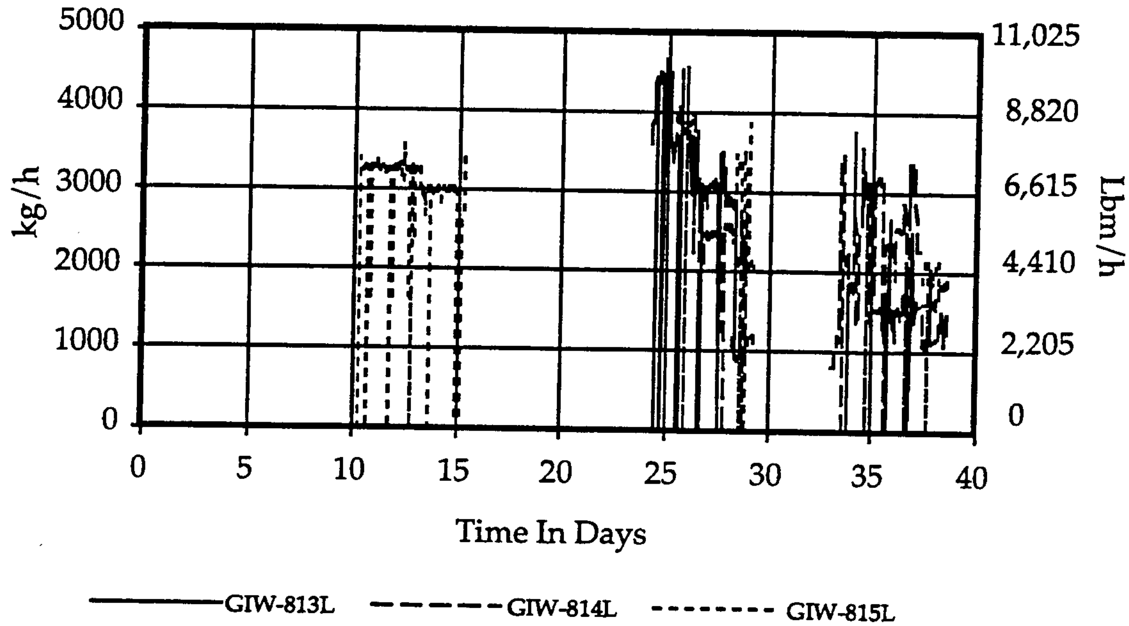


Figure 13b. Steam injection rates into the lower screened intervals of wells GIW-818, 819, and 820 during the second injection pass.

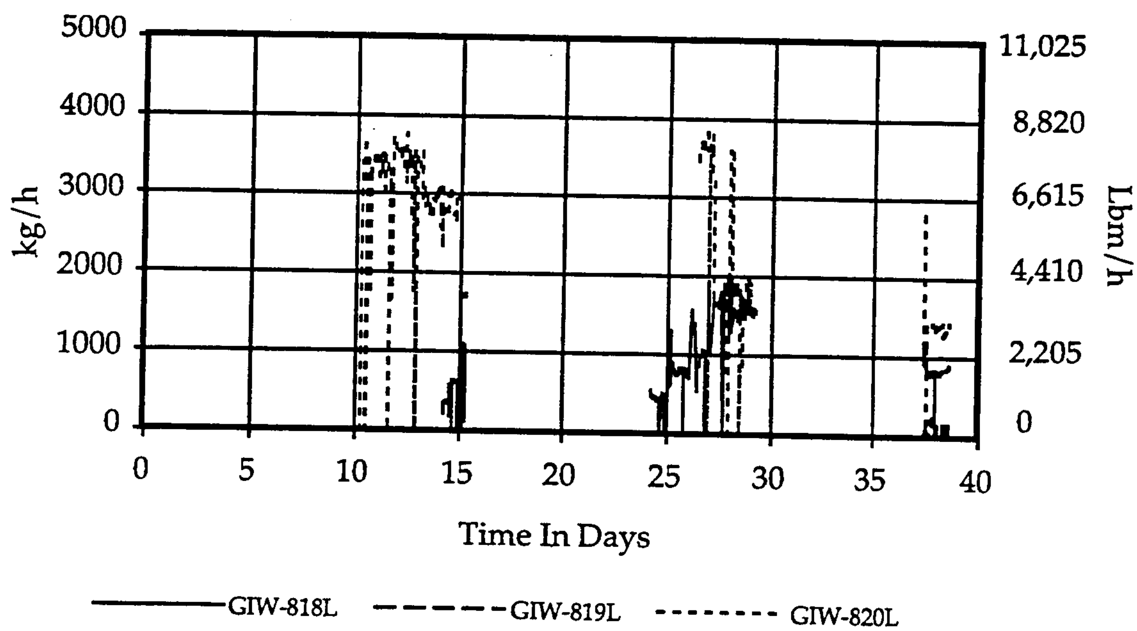


Figure 15. Extraction well vapor temperatures during the second pass.

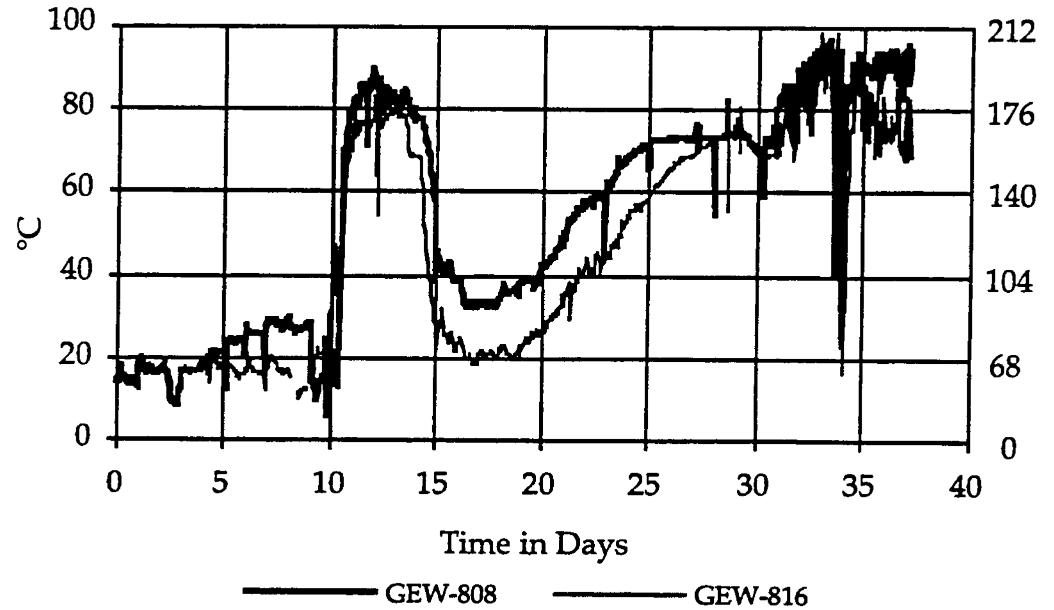
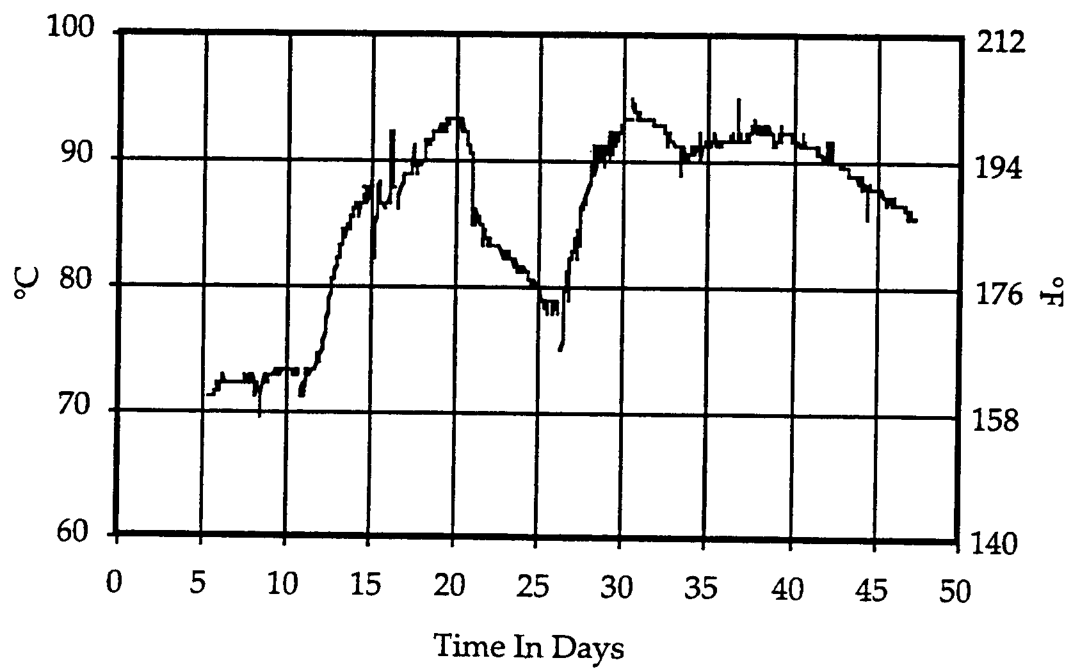


Figure 14. Effluent water temperature during the second pass.



Summary of Expenditures

Well Construction Costs

A total of ten wells were drilled by the reverse circulation rotary drilling technique. Of the ten, two were extraction wells, six were combination steam injection-electrical heating wells, and two were lost during construction. The drilling contractor supplied all materials with the exception of the anode graphite and steel casings used in the injection wells. The drilling contractor received $228,000 in 1992 dollars. The average cost per well including all completion materials was approximately $25,000 each or $540/meter ($165/ft). This does not include the cost of the Laboratory's drilling geologist or technician support preparing the casing. Table 5 summarizes some of the costs for construction of the injection and extraction wells.

The combination Electrical Resistance Tomography (ERT)-temperature wells were drilled with a hollow stem auger

Table 5. Summary of costs to construct injection and extraction wells. Values denoted by an asterisk are 1994 dollars. All others are in 1992 dollars.

Item	Unit Cost	Remarks
Drill Rig & Crew		Per Hour
Mobilization and demobilization	$10,000.00	One time expense
Set conductor casings	$2,700.00/hole	8 wells
Rig down & clean up	$1,500.00/hole	8 wells
Well development	$136.00/h	(8 wells @ 8 hrs ea.)
0.2 m x 27.4 m (8" x 90' nominal) SST ext. well screen*	$285.00/m	$87/ft
0.2 m x 13.7 m (8" x 45' nominal) fiberglass pipe	$86.30/m	$26.30/ft
0.1 m x 62.5 m (4" x 205' nominal) steel injection casing	$15.60/m	$4.76/ft
0.1 m x 6.1 m (4" x 20' nominal) SST injection screen*	$87/m	$26.50/ft
0.05 m x 33.8 m (2" x 111' nominal) steel elec. heating casing	$8.40/m	$2.55/ft
0.05 m x 3 m (2"x 10' nominal) SST elec. heating screen*	$78.75/m	$24.00/ft
Haliburton API Class G grout*	$6.00/94# bag	~52 bags/well
Silica sand*	$6.35/100# bag	~32 bags/well
#3 Sand*	$4.94/100# bag	~2.5 bags/well
Pea gravel*	$3.88/75# bag	~44 bags/well
Anode graphite (GP-BB-6P11)	$45.50/70# bag	~7 bags/well
Bentonite*	$3.80/50# bag	~14 bags/well
Steam well head completions	$1,000/casing	
Electrical well head completions	$300/casing	

rig. On average it took 5 days of drill rig time to complete each well because of extensive sampling and characterization when the wells were drilled. In 1992, the auger rig cost us $150 per hour and included the rig, a driller and helper. It did not include the Laboratory's drilling geologist or technician support for preparing and installing the casing and instrumentation. The average cost of drilling and constructing each well, including materials, was approximately $10,000 each for an average of $200/meter ($60/ft). A summary of monitoring well construction costs is provided in Table6.

Electrical heating-only wells were drilled with a hollow stem auger rig. The wells were drilled to a nominal depth of 36.2 meters (118') and an diameter of 0.3 m (11.75"). Electrical heating-only wells took approximately 5 days to drill and complete. The average cost per well was $8,000. A summary of electrical heating well completion costs are given in Table 7.

Surface Equipment Costs: Electrical Heating Equipment

The major surface electrical equipment consisted of a high voltage

Table 6. Summary of costs to construct monitoring wells. Values denoted by an asterisk are 1994 dollars. All others are given in 1992 dollars.

Item	Unit Cost	Remarks
Drill Rig & Crew	$150.00/h	~32 h/well
0.05 m x 48.8 m (2" x 160') fiberglass pipe (w/threaded end adapters)	$20.00/m	$6.10/ft
0.05 m x 30.5 m (1" x 100' nominal) PVC piezometer casing	$2.95/m	$0.90/ft
#3 Sand*	$4.94/100# bag	~11 bags/well
Silica sand*	$6.35/100# bag	~12 bags/well
Haliburton API Class G grout*	$6.00/94# bag	~80 bags/well

Table 7. Summary of costs to construct electrical heating-only wells. Values denoted by an asterisk are 1994 dollars. All others are given in 1992 dollars.

Item	Unit Cost	Remarks
Drill Rig & Crew	$150.00/h	~40 h/well
0.05 m x 51.9 m (2" x 170' nominal) Steel casing	$8.37/m	$2.55/ft
0.05 m x 6.1 m (2" x 20' nominal) SST screen	$78.75	$24.00/ft
Anode graphite (GP-BB-6P11)	$45.50/70# bag	~14 bags/well
Pea gravel*	$3.88/75# bag	~30 bags/well
Bentonite*	$3.80/50# bag	~10 bags/well
#0/30 Sand*	$4.44/100# bag	~5 bags/ well
Silica sand*	$6.35/100# bag	~6 bags/well
Haliburton API Class G grout*	$6.00/94# bag	~14 bags/well

switch, transformer, 4,000 amp circuit breaker, and a low voltage distribution panel. Installation of the electrical heating equipment occurred over a 6 month period. Labor costs for the installation was approximately $150,000 in 1992 dollars. Miscellaneous material costs for items such as conduit, cable trays, wiring, concrete pads to place the transformer, breaker, and switch panel on, etc. amounted to an additional $67,000. Total costs for construction, installation, and materials was approximately $375,000. A summary of electrical heating costs are provided in Table 8.

Table 8. Summary of costs to construct and install electrical heating equipment.

Item	Unit Cost	Remarks
Construction Labor	$150,000	Over 6 months
Transformer	$50,000	
4,000 Amp Circuit Breaker	$28,000	
Low Voltage Switch Panel	$20,200	
Electrical Cable (LV switch to wells #350 3/c THHN/THWN)	$23.60/m	(1000' @ $7.20/ft)
Electrical Cable (Transformer to LV switch #500 3/c THHN/THWN)	$33.80/m	(1000' @ $10.30/ft)
Miscellaneous Materials	$67,000	

Surface Equipment Costs: Steam Injection Equipment

The major surface equipment necessary for the steam injection operation included the steam boiler, steam distribution piping, pressure regulators and valves, and the natural gas line for the boiler. The nearest natural gas connection for the boiler was about 300 m (1,000') away. The cost to install a 0.1 m (4") gas line to supply the boiler was approximately $80,000. Water and electrical utilities added another $20,000. The boiler used for the job was leased for $17,000 per month (1993 dollars). Labor to install the remaining steam equipment such as steam lines, pressure regulators, valves manifolds, plumbing of boiler auxiliary equipment, etc. was $194,000. Miscellaneous material costs added another $38,000. The total cost of construction and installation was approximately $395,000. A summary of the major costs associated with the construction of steam injection facilities is provided in Table 9. Total manhours for both the steam injection and electrical heating construction are presented in Table 10.

Operational Energy Costs

Boiler utility costs are summarized in Table 11. The average utility cost for both the first and second passes was $117/h. This includes the cost of natural gas, water and electrical power. Utility rates charged to the Laboratory are as follows:

Natural gas: 39¢/Therm, where one therm is 2,832 m^3 (100,000ft^3) of gas,

Electricity: 6¢/kwh,

Water: $1.25/2.84 m^3 ($1.25/100ft^3).

Table 9. Summary of costs to construct and install steam injection equipment.

Item	Unit Cost	Remarks
Construction Labor	$194,000	Over 6 months
Boiler Lease	$17,300/Mo.	
Boiler Utility Installation/Set up	$100,000	Labor and Materials
Steam Hose	$32.50/m	(400' @ $9.90/ft)
Miscellaneous Materials	$38,000	Valves, Fittings, etc.

Table 10. Summary of manhours required for steam and electrical heating construction.

Craft Type	Steam Construction Manhours	Electrical Construction Manhours
Laborers	242	313
Carpenters	336	134
Electricians	385	1,426
Plumbers	1,579	4
Painters	71	0
Riggers	44	92
Total	2,657	1,687

The cost of boiler electrical power is based upon requirements for a 20Hp blower and 20Hp feed water pump operating 100% of the time. The total cost for boiler utilities was $157,000. Based upon calculations by Kenneally (see *Modeling Steam Locations During a Steam Injection Process for Subsurface Gasoline Spills,,* this volume), 166,000 m^3 (217,120yd^3) of soil was heated to 100°C (212 °F). The utility cost on a per unit volume of soil heated basis came to 95¢/m^3 (72¢/yd^3). This does not include two boiler operators per shift, for three shifts per day while the boiler was running. During the electrical heating portion of the project a total of 7.2x10^8 kJ (200,000 kWh) of energy was deposited into both the upper and lower clay-rich zones at a cost of $216/kJ (6¢/kWh) The total cost amounted to $12,000. An estimated 6,500 m^3 or 8,500yd^3, (see Buettner, *The Electrical Preheating Phase of Dynamic Underground Stripping* in this volume) of soil in the upper zone was heated from a few degrees centigrade to 70° C (158 °F) using 2x10^8 kJ (55,000kWh) of energy. The unit cost energy to heat the upper zone electrically was 51¢/m^3 (39¢/yd^3). For the lower zone, an estimated 11,700 m^3 (15,300/yd^3) was heated from a few degrees centigrade to 20 °C (68°F) using 5.2x10^8 kJ (145,000 kWh) of electrical energy. Unit energy costs for the lower zone amounted to 74¢/m^3 (57¢/yd^3). The average energy cost for both zones was 63¢/m^3 (48¢/yd^3). Table 12 summarizes electrical energy costs incurred during electrical heating.

Table 11. Utility costs for the first and second passes of steam injection.

	Cumulative Gas Input ft^3	Cumulative Gas Input m^3	Cumulative Gas Cost 1993 Dollars	Average Gas Cost 1993 Dollars/h
1st Pass	$2.57x10^{10}$	7.2810^8	$99,502	$121.72
2nd Pass	$1.27x10^{10}$	$3.60x1^8$	$49,532	$100.27
Combined	$3.84x10^{10}$	$1.09x10^9$	$149,033	$111.00
	Cumulative Water Input Gallons	Cumulative Water Input Cubic Meters	Cumulative Water Cost in 1993 Dollars	Average Water Cost in 1993 Dollars/h
1st Pass	$2.43x10^6$	$9.19x10^3$	$4,056	$4.53
2nd Pass	$1.19x10^6$	$4.51x10^3$	$1,990	$3.79
Combined	$3.62x10^6$	$1.37x10^4$	$6,046	$4.16
	Cumulative Elec. Input kWh	Cumulative Elec. Input kJ	Cumulative* Elec. Cost in 1993 Dollars	Average* Elect. Cost in 1993 Dollars/h
1st Pass	$2.46x10^4$	$1.15x10^6$	$1,477	$1.80
2nd Pass	$1.50x10^4$	$7.01x10^5$	$901	$1.82
Combined	$3.96x10^4$	$1.85x10^6$	$2,379	$1.81
Average Utility Cost/h for Both Passes				$116.97

*Assumes that 20 Hp boiler feed water pump and 20 Hp blower are on 100% of the time.

Table 12. Utility costs for electrical heating.

	Cumulative Electrical Input kWh	Cumulative Electrical Input kJ	Cumulative Electrical Cost 1993 Dollars	Average Cost per Unit Heated 1993 Dollars
Upper Zone	55,000	$2.0x10^8$	$3,300	51¢/m^3
Lower Zone	145,000	$5.2x10^8$	$8,700	74¢/m^3
Combined	200,000	$7.2x10^8$	$12,000	63¢/m^3

Site Safety

Personnel safety was a primary concern during the operation of the Dynamic Stripping facility. Detailed procedures and checklists were written to cover all aspects of steam injection, electrical heating, well maintenance, geophysical monitoring, personnel training, emergency procedures, and quality control. The primary document written to cover Dynamic Stripping safety issues was LLNL Operational Safety Procedure L-52, *Cleanup Of Ground Water Contaminated With Gasoline By Using The Dynamic Underground Stripping Process* . Although some of the criteria in OSPL-52 was site specific, the majority of the requirements are applicable to other sites. Additional safety procedures were written to address well construction in gasoline contaminated areas (LLNL Operational Safety Procedure 406.2, *Borehole Drilling in Gasoline Contaminated Areas*) and treatment of gasoline contaminated vapors (LLNL Operational Safety Procedure 406.4, *Treatment of Vapors and Ground Water Using Treatment Facility F*). Copies of the OSP's are included in Appendix B.

Supplementing the OSP's were a number of checklists and logs. Copies of those checklists are included in Appendix C. The use of checklists ensured that operational details were not overlooked during the startup and operation of the facility.